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Ringgenberg

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(54) **NON-ELECTRONIC AIR CHAMBER PRESSURE SENSOR**

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G01B 7/14	(2006.01)
E21B 34/00	(2006.01)

(52) **U.S. Cl.**

CPC ***G01M 3/02*** (2013.01); ***E21B 34/063*** (2013.01); ***E21B 34/08*** (2013.01); ***E21B 34/14*** (2013.01); ***E21B 47/06*** (2013.01); ***G01B 7/14*** (2013.01); ***G01L 9/0033*** (2013.01); *E21B 2034/002* (2013.01); *E21B 2034/007* (2013.01)

(58) **Field of Classification Search**

CPC E21B 34/103; E21B 34/063; E21B 2034/002; E21B 2034/007; E21B 47/06; E21B 47/1025; G01L 9/14; G01L 9/16; G01L 9/0082; G01L 9/026; G01L 2009/0067; F16K 37/0033

USPC 73/728; 137/312, 551, 557

See application file for complete search history.

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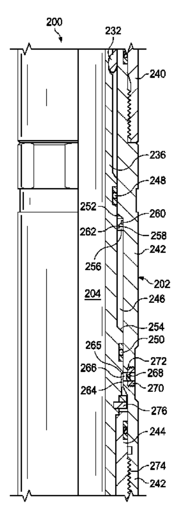
Primary Examiner — Jennifer H Gay

(57) **ABSTRACT**

An apparatus for use in a wellbore having a housing having at least one chamber capable of receiving a fluid, a sealed annular volume, and a non-electronic pressure sensor disposed in the sealed annular volume. The non-electronic sensor includes a sealed, compressible container. Positioned within the sealed, compressible container are first and second magnets that are separated by a first distance when a fluid within the sealed annular volume is at a first pressure. When the fluid in the sealed annular volume is at a second pressure, the first and second magnets are separated by a second distance.

25 Claims, 6 Drawing Sheets



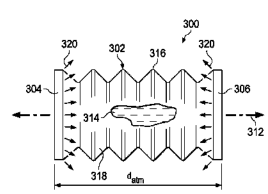


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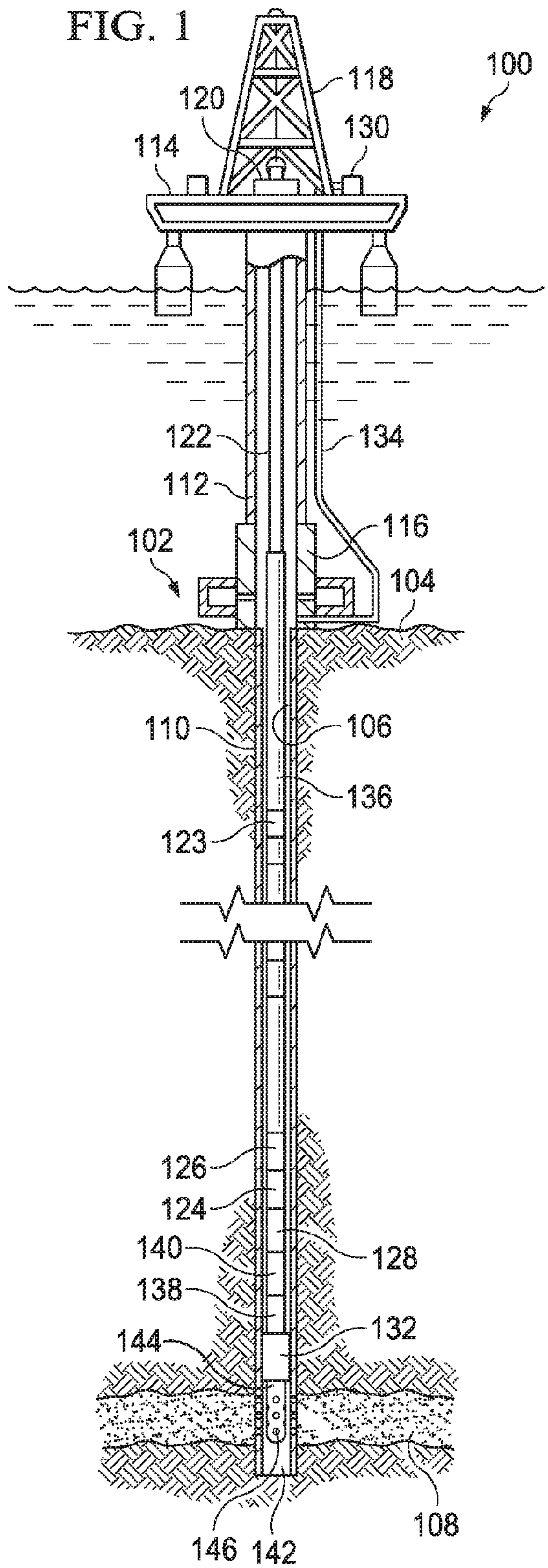
FIG. 1



100
118
120
130
114
122
134
112
116
102
104
110
106
136
123
126
124
128
140
138
132
144
108
146
142

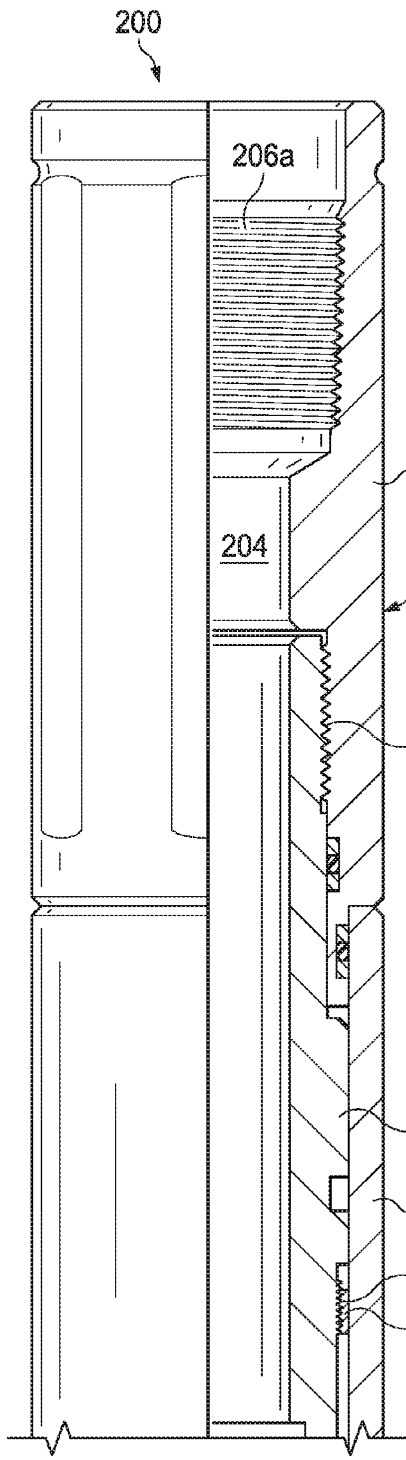

200
206a
238
204
202
218
214
240
220
216

FIG. 2A

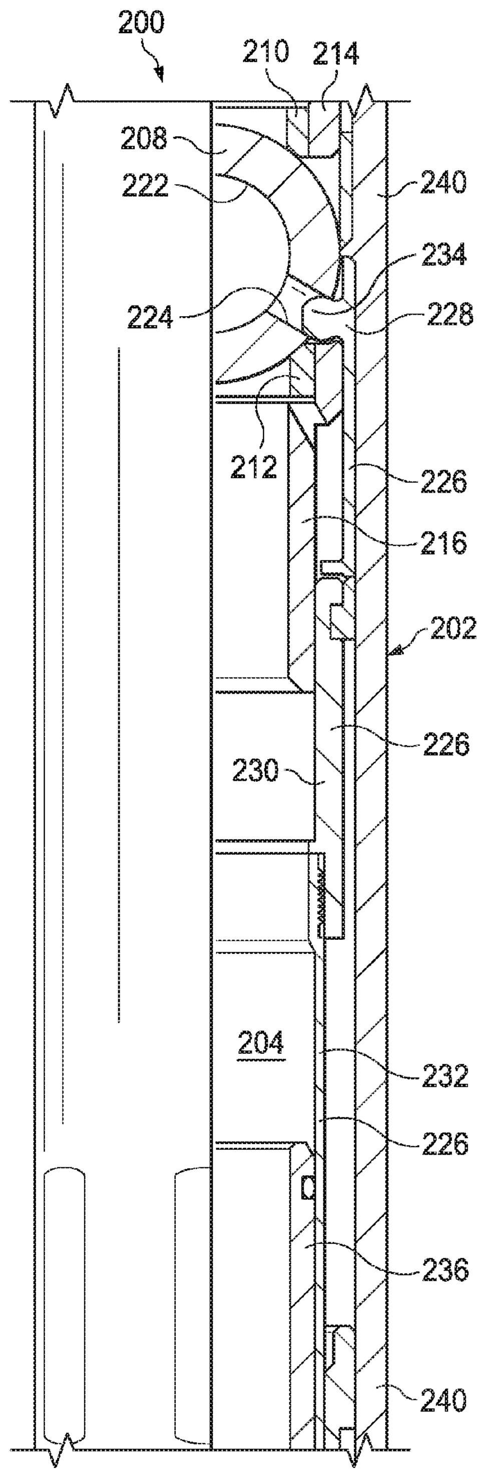

200
210
214
208
222
240
234
224
228
212
226
216
202
226
230
204
232
226
236
240

FIG. 2B

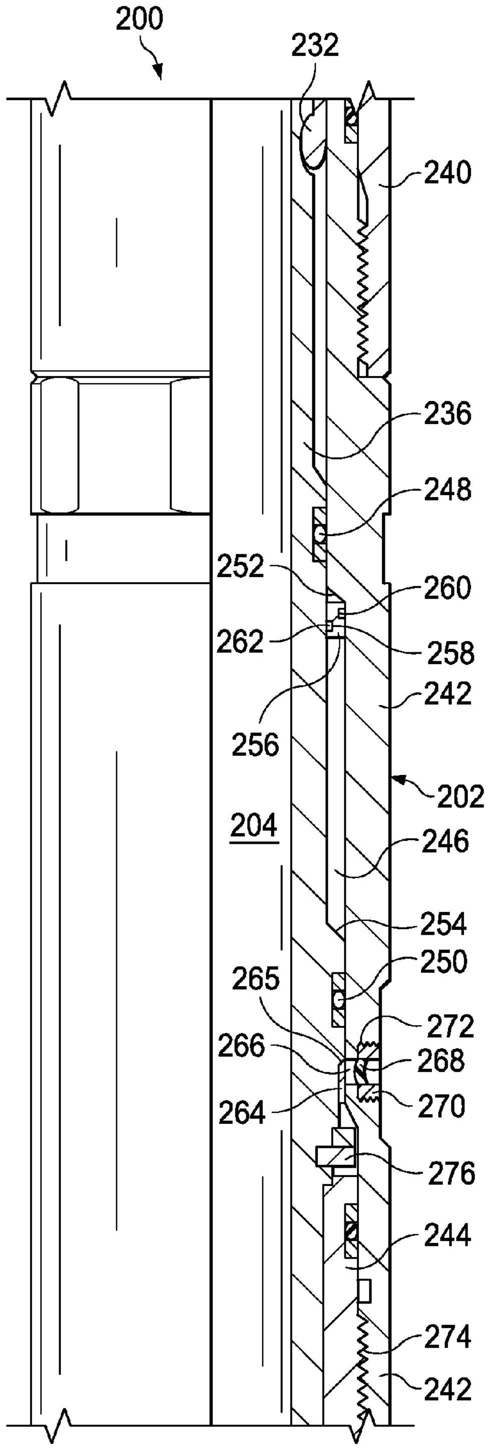

200
232
240
236
248
252
260
262
258
242
256
202
204
246
254
250
265
272
266
268
264
270
276
244
274
242

FIG. 2C

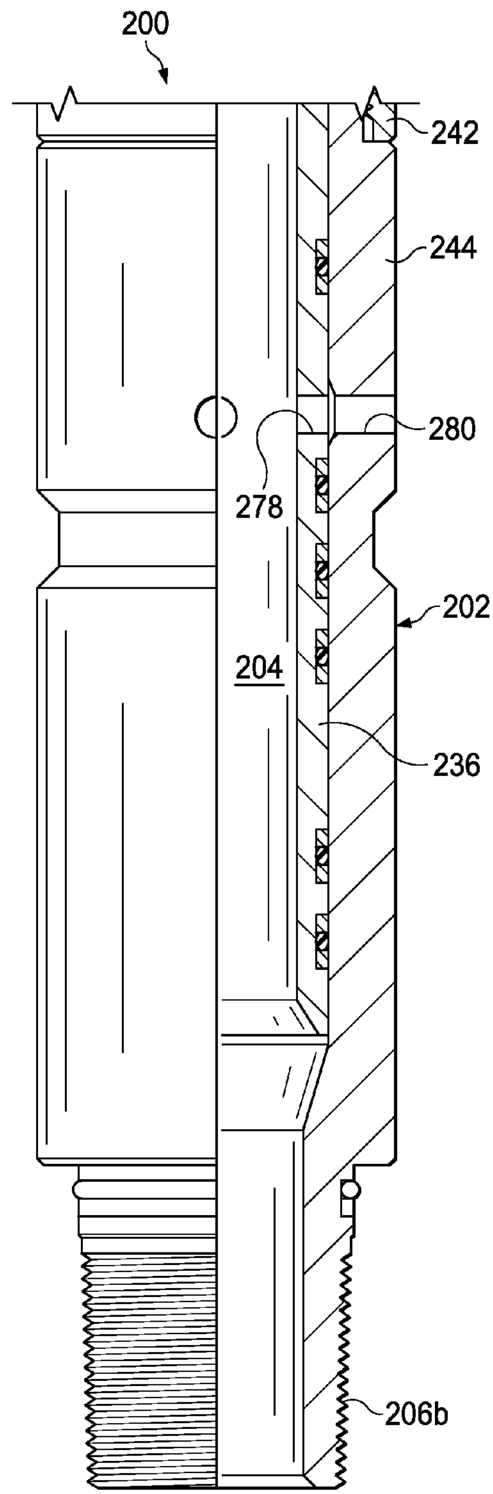

200
242
244
280
278
202
204
236
206b

FIG. 2D

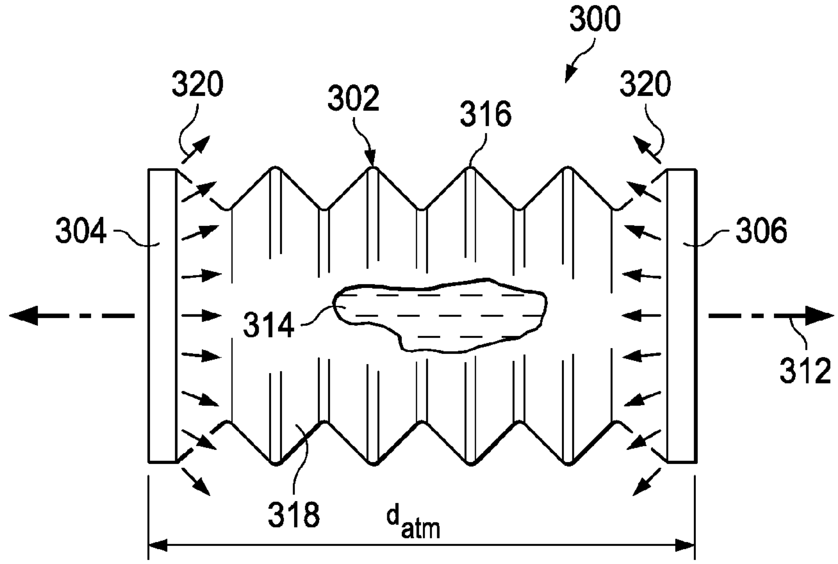


FIG. 3

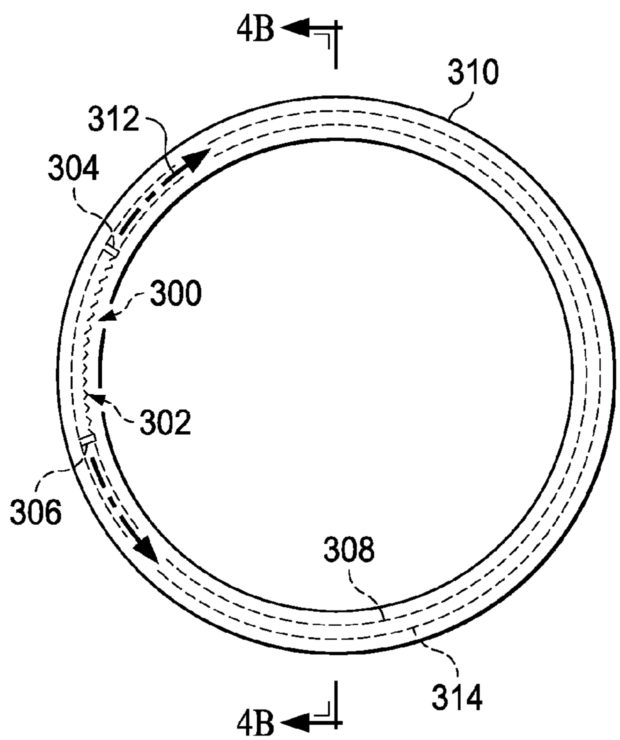


FIG. 4A

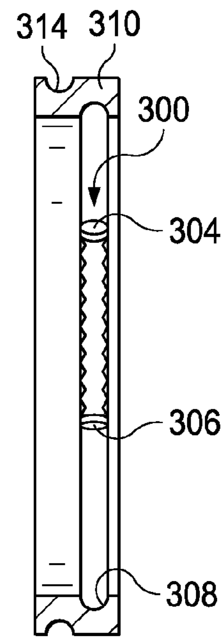


FIG. 4B

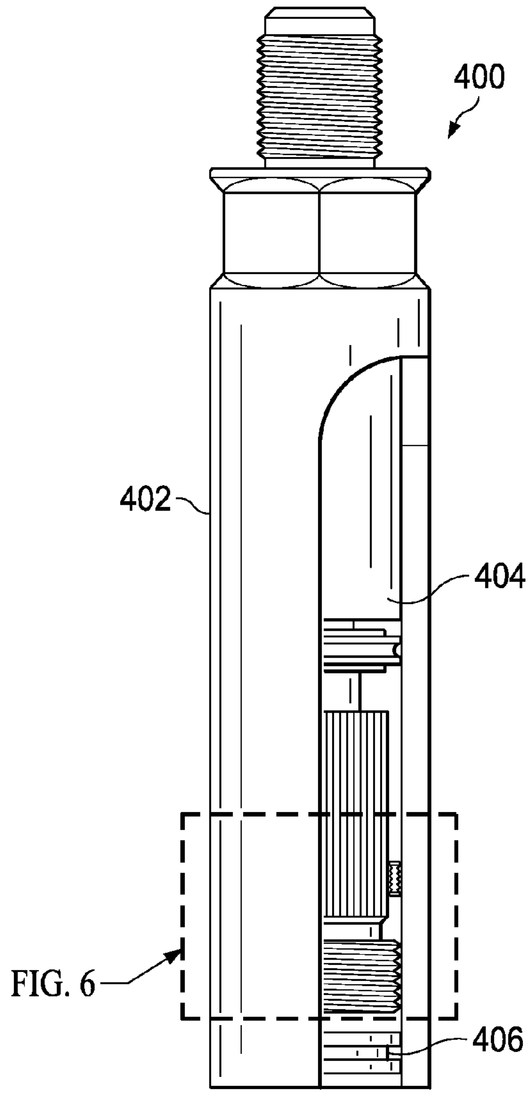


FIG. 5

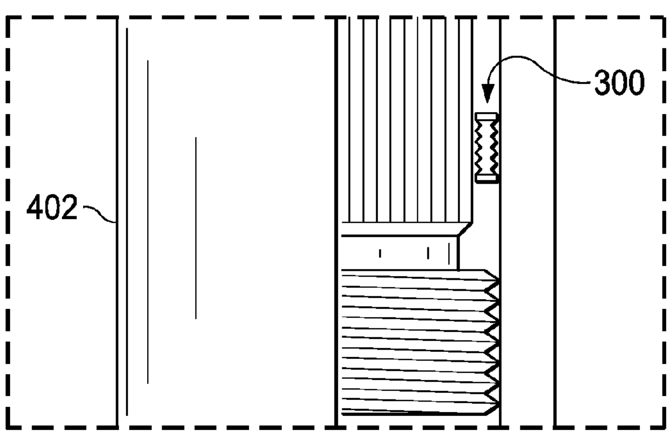


FIG. 6

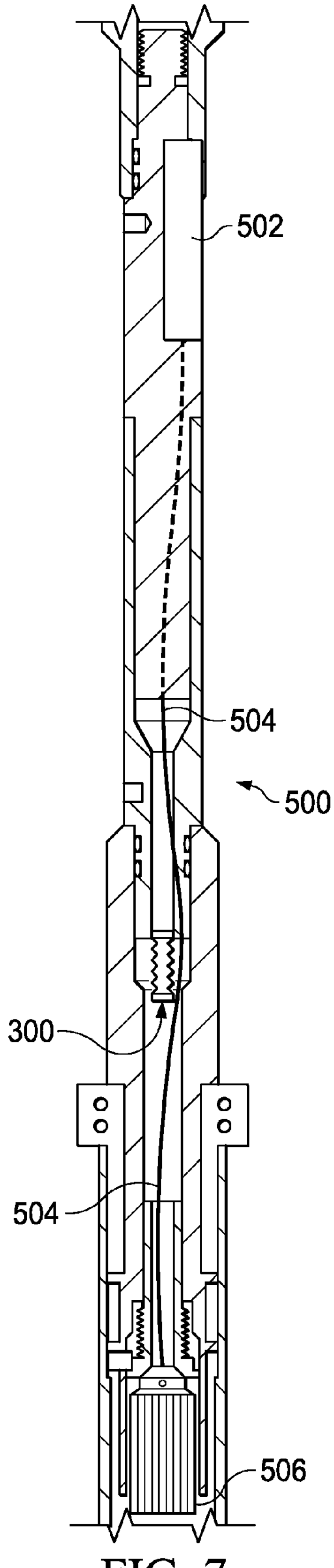


FIG. 7

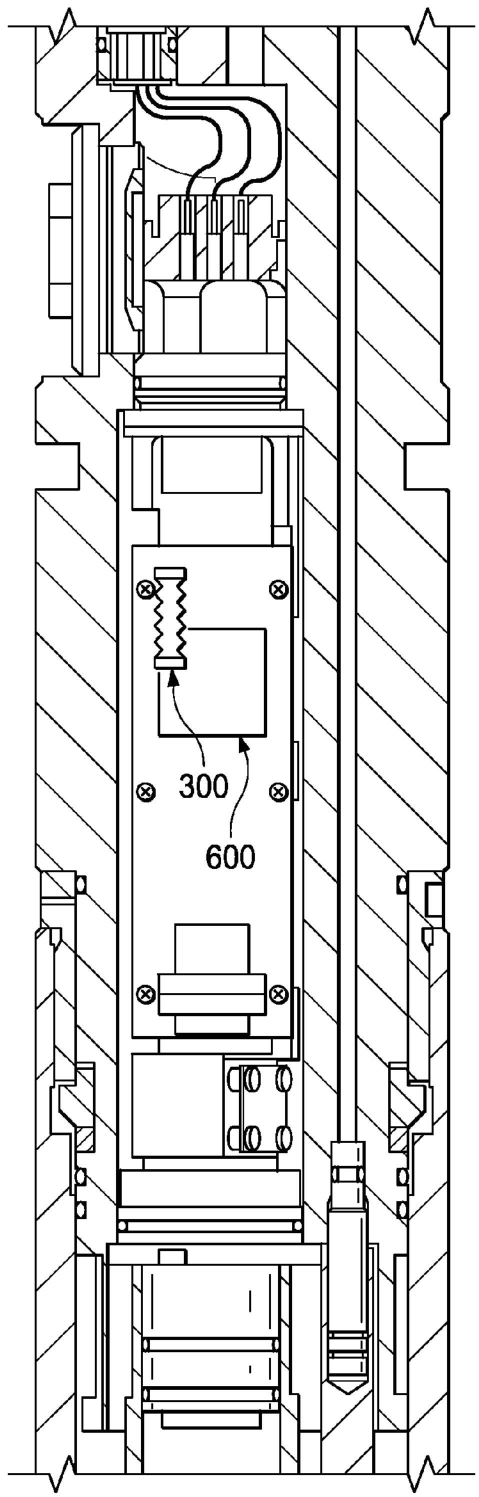


FIG. 8

NON-ELECTRONIC AIR CHAMBER PRESSURE SENSOR

CROSS REFERENCE TO RELATED APPLICATIONS

This application claims priority to PCT Patent Application Number PCT/US13/32278 filed on Mar. 15, 2013 entitled NON-ELECTRIC AIR CHAMBER PRESSURE SENSOR the entire teachings of which are incorporated herein.

BACKGROUND

1. Field of the Invention

The present disclosure relates generally to the valves used in wellbores and more specifically to methods and apparatuses for determining seal integrity within the valves.

2. Description of Related Art

Wells are drilled at various depths to access and produce oil, gas, minerals, and other naturally-occurring deposits from subterranean geological formations. The drilling of a well is typically accomplished with a drill bit that is rotated within the well to advance the well by removing topsoil, sand, clay, limestone, calcites, dolomites, or other materials. The drill bit is attached to a drill string that may be rotated to drive the drill bit and within which drilling fluid, referred to as “drilling mud” or “mud”, may be delivered downhole. The drilling mud is used to cool and lubricate the drill bit and downhole equipment and is also used to transport any rock fragments or other cuttings to the surface of the well.

As wells are established it is often useful to obtain information about the well and the geological formations through which the well passes. Information gathering may be performed using tools that are delivered downhole by wireline, tools coupled to or integrated into the drill string, or tools delivered on other types of testing strings. Due to the variation in pressures and temperatures associated with downhole fluids, hydraulic and pneumatic mechanisms incorporated into these tester valves may become less reliable and functional when subjected to these downhole conditions. After each use of the tester valves, the tester valve may be completely disassembled and rebuilt. The tester valve may then be pressure tested. The tester valve may have one or more sealed air chambers. However, there is no easy way to determine whether the sealed air chambers have leaks after the tester valve has been subject to the pressure test. Systems, apparatuses, and methods for determining seal integrity after initial assembly or after rebuilding the tester valve are desirable.

SUMMARY

The problems presented by existing systems and methods for determining seal integrity in downhole tools are solved by the systems and methods of the illustrative embodiments described herein. In one embodiment, a valve for use in a wellbore includes a housing configured to form a central passage, a first valve member positionable in an open or closed position to allow or prevent flow through the central passage, and a second valve member positionable in an open or closed position to allow or prevent fluid communication between the central passage and an annulus positioned between the valve and the wellbore. The valve further includes an actuation assembly connected to the first valve member and the second valve member that is movable between a first position and a second position to selectively position each of the first valve member and the second valve member. A sealed annular volume formed between the sec-

ond valve member and the housing, and a non-electronic pressure sensor is disposed in the sealed annular volume. The non-electronic pressure sensor includes a sealed, compressible container, a first magnet, and a second magnet. The first and second magnets are positioned within the sealed, compressible container such that the first and second magnets are separated by a first distance when a fluid within the sealed annular volume is at a first pressure. Conversely, the first and second magnets are separated by a second distance when the fluid in the sealed annular volume is at a second pressure.

In another illustrative embodiment, an apparatus for use in a wellbore includes a housing having at least one chamber capable of receiving a fluid, a sealed annular volume, and a non-electronic pressure sensor disposed in the sealed annular volume. The non-electronic pressure sensor includes a sealed, compressible container, a first magnet, and a second magnet. The first and second magnets are positioned within the sealed, compressible container such that the first and second magnets are separated by a first distance when a fluid within the sealed annular volume is at a first pressure. Conversely, the first and second magnets are separated by a second distance when the fluid in the sealed annular volume is at a second pressure.

In another illustrative embodiment, a method of determining whether a seal has failed in a downhole apparatus will be described. The downhole apparatus includes a first chamber and a second chamber with a sealed, compressible container disposed in the first chamber. The sealed, compressible container includes first and second magnets disposed therein that are separated by a first distance when a fluid within the sealed, compressible container is at a first pressure. The method for determining whether the seal has failed includes the steps of changing a pressure of fluid within the second chamber, determining a measured distance between the magnets, and comparing the measured distance to the first distance.

In yet another illustrative embodiment, a method for determining whether a chamber in a downhole apparatus is sealed will be described. The downhole apparatus includes the chamber with a sealed, compressible container disposed therein. The sealed, compressible container includes first and second magnets disposed within the container such that the first and second magnets are separated by a first distance when a fluid within the sealed, compressible container is at a first pressure. The method for determining whether the chamber is sealed includes determining a measured distance between the magnets prior to delivering the downhole apparatus into a wellbore and then comparing the measured distance to the first distance.

Other objects, features, and advantages of the invention will become apparent with reference to the drawings, detailed description, and claims that follow.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. **1** illustrates a schematic depiction of a well test string, including a tester valve, in place on an offshore well;

FIGS. **2**A-**2**D illustrate partial, cross-sectional views of a testing valve according to an illustrative embodiment for use in the well test string shown in FIG. **1**;

FIG. **3** illustrates a side view of a non-electronic pressure sensor according to an embodiment;

FIG. **4**A illustrates a top view of a bumper that may be used in the pressure valve shown in FIGS. **2**A-**2**D with the non-electronic pressure sensor of FIG. **3** shown disposed within the bumper via hidden lines;

FIG. **4**B illustrates a cross-sectional view of the bumper of FIG. **4**A taken along **4**A-**4**A showing a side view of the non-electronic pressure sensor of FIG. **3** disposed within an inner groove of the bumper;

FIG. **5** illustrates a partial cross-sectional view of a battery housing that may be used in a well string according to one illustrative embodiment;

FIG. **6** illustrates a detailed view of the battery housing of FIG. **5**, illustrating a non-electronic pressure sensor positioned within the battery housing;

FIG. **7** illustrates a cross-sectional view of an electronic pressure gauge according to an illustrative embodiment for use in a wireline tool with a non-electronic pressure sensor positioned within the electronic pressure gauge; and

FIG. **8** illustrates a cross-sectional view of an electronic pressure gauge according to an illustrative embodiment for use in a wireline tool with a non-electronic pressure sensor of positioned within the electronic pressure gauge.

DETAILED DESCRIPTION OF ILLUSTRATIVE EMBODIMENTS

In the following detailed description of the illustrative embodiments, reference is made to the accompanying drawings that form a part hereof. These embodiments are described in sufficient detail to enable those skilled in the art to practice the invention, and it is understood that other embodiments may be utilized and that logical, structural, mechanical, electrical, and chemical changes may be made without departing from the spirit or scope of the invention. To avoid detail not necessary to enable those skilled in the art to practice the embodiments described herein, the description may omit certain information known to those skilled in the art. The following detailed description is, therefore, not to be taken in a limiting sense, and the scope of the illustrative embodiments is defined only by the appended claims.

The apparatuses and methods described herein provide monitoring of seals enclosed in downhole tools using non-electronic pressure sensors. The non-electronic pressure sensor provides for a non-electric system that monitors the seals enclosed in the downhole tools without disassembling the downhole tools and without introducing additional leak paths into sealed areas of the downhole tool. Electronic devices are expensive and can be dangerous and unreliable when used in downhole tools because of the harsh environments in which the downhole tools operate. The temperatures downhole often exceed the operational capabilities of electronic sensors, circuits, batteries, and other electronic devices. Downhole tools may be exposed to extreme changes in temperature and pressure that can cause electronic devices to malfunction. Additionally, downhole tools are exposed to fluids that conduct electricity. Should a seal become compromised, thereby exposing an electronic device to fluids that conducts electric, the electronic device may malfunction or even create a safety hazard during tool maintenance. For example, lithium battery-powered gauges have been known to explode during tool maintenance if the lithium battery-powered gauges have been exposed to conducting fluids. By using a non-electronic pressure sensor, determining whether a seal has failed may be assessed safely and without unnecessary disassembly of the tool.

Some of the illustrative embodiments described in the following disclosure, such as a tester valve in which a non-electronic pressure sensor resides, may be used to evaluate a formation through which a well passes. Tester valves, or other downhole devices that incorporate the non-electronic pressure sensors described herein may be used with any of the

various techniques employed for evaluating formations including, without limitation, wireline formation testing (WFT), measurement while drilling (MWD), and logging while drilling (LWD). The various valves and tools described herein may be delivered downhole as part of a wireline-delivered downhole assembly or as a part of a drill string.

As used herein, the phrases “fluidly coupled,” “fluidly connected,” and “in fluid communication” refer to a form of coupling, connection, or communication related to fluids, and the corresponding flows or pressures associated with these fluids. Reference to a fluid coupling, connection, or communication between two components describes components that are associated in such a way that a fluid can flow between or among the components.

Referring to FIG. **1**, a floating platform **100** is positioned over a submerged oil or gas well **102** located in the sea floor **104** having a bore hole **106** that extends from the sea floor **104** to a submerged formation **108** to be tested. The bore hole **106** (also referred to as a wellbore) may be lined by a casing **110** that may be cemented into place. A subsea conduit **112** extends from a deck **114** of the floating platform **100** into a wellhead installation **116**. The floating platform **100** further includes a derrick **118** and a hoisting apparatus **120** for raising and lowering tools to drill, test, and complete the oil or gas well **102**.

A testing string **122** is lowered into the bore hole **106** of the oil or gas well **102**. The testing string **122** includes such tools as a slip joint **123** to compensate for the wave action of the floating platform **100** as the testing string **122** is lowered into place. The testing string **122** may include a tester valve **124**, a circulation valve **126**, and a check valve assembly **128**.

The slip joint **123** may be similar to that described in U.S. Pat. No. 3,354,950 to Hyde. The circulation valve **126** may be an annulus pressure responsive type and may be similar to that described in U.S. Pat. No. 3,850,250 to Holden et al, or may be a combination circulation valve and sample entrapment mechanism similar to those disclosed in U.S. Pat. No. 4,063,593 to Jessup or U.S. Pat. No. 4,064,937 to Barrington. The circulation valve **126** may also be the re-closable type as described in U.S. Pat. No. 4,113,012 to Evans et al.

The check valve assembly **128** as described in U.S. Pat. No. 4,328,866 filed Mar. 7, 1980, which is annulus pressure responsive, may be located in the testing string **122** below the tester valve **124** of the present invention.

The tester valve **124**, the circulation valve **126** and the check valve assembly **128** may be operated by fluid annulus pressure exerted by a pump **130** on the deck **114** of the floating platform **100**. Pressure changes are transmitted by a pipe **134** to a well annulus **136** between the casing **110** and the testing string **122**. Well annulus pressure is isolated from the formation **108** by a packer **138** having an expandable sealing element **132** thereabout set in the casing **110** adjacent to the formation **108**. The packer **138** may be any suitable packer, such as for example a Baker Oil Tool™ Model D packer, an Otis™ type W packer or the Halliburton Services EZ Drill® SV packer.

The testing string **122** includes a tubing seal assembly **140** at the lower end of the testing string **122**. The tubing seal assembly **140** stabs through a passageway within the packer **138** to form a seal isolating the well annulus **136** above the packer **138** from an interior bore portion **142** of the well immediately adjacent the formation **108** and below the packer **138**.

A perforated tail piece **144**, or other production tube, is located at the bottom end of the tubing seal assembly **140** to allow formation fluids to flow from the formation **108** into the flow passage of the testing string **122**. Formation fluid is admitted into the interior bore portion **142** through perforations **146** provided in the casing **110** adjacent the formation **108**.

A formation test controls the flow of fluid from the formation **108** through the flow channel in the testing string **122** by applying and releasing fluid annulus pressure to the well annulus **136** by the pump **130** to operate the tester valve **124**, the circulation valve **126** and the check valve assembly **128**. The formation test measures the pressure build-up curves and fluid temperature curves with appropriate pressure and temperature sensors in the testing string **122** as described in more detail in the aforementioned patents, all of which are incorporated herein by reference.

While the well **102** is illustrated as being an offshore well in FIG. **1**, the systems, apparatuses, and methods described herein will function equally well in an on-shore well.

Referring now to FIGS. **2A-2D**, a tester valve **200** according to an illustrative embodiment will be described in more detail. The tester valve **200** is similar to the tester valve **124** shown in FIG. **1** and is also similar in function to the tester valve described in U.S. Pat. No. 5,341,883, which is hereby incorporated by reference. The tester valve **200** is depicted schematically in FIGS. **2A-2D** and includes a valve housing **202** that is substantially cylindrical in shape and includes a central passage **204** extending the length of the valve housing **202**. The valve housing **202** includes threaded connection components **206***a* (shown in FIG. **2A**) and **206***b* (shown in FIG. **2D**) to allow connection of the tester valve **200** within a test string, such as the testing string **122** shown in FIG. **1**, or to other downhole devices. The valve housing **202** may be comprised of a number of sub-housing units that when connected form the valve housing **202**. In one illustrative embodiment, the valve housing **202** may be comprised of sub-housing units such as an upper adapter unit **238**, a first valve housing unit **240**, a rupture disc housing unit **242**, and a bypass housing unit **244**.

A first valve member **208** is rotatably positioned within the valve housing **202** and is axially anchored within the valve housing **202** by upper and lower ring-shaped valve seats **210**, **212** positioned above and below the first valve member **208**. The upper valve seat **210** is disposed adjacent an upper seat carrier **214**, the upper seat carrier **214** being connected to the valve housing **202** at a threaded connection **218**. The lower valve seat **212** is supported by a lower seat carrier **216**. The lower seat carrier **216** is connected to the upper seat carrier **214** above the first valve member **208** at threaded connection **220** (shown in FIG. **2A**). In one embodiment, the first valve member **208** may be a ball valve member.

The first valve member **208** defines a valve bore **222** therethrough and has a recess **224**. An actuation assembly **226** is configured to slide along the longitudinal axis of the valve housing **202** to move the first valve member **208** between an open and closed position. The actuation assembly **226** includes an actuation arm **228**, a mandrel **230**, and a spring ring **232** that are connected so the actuation arm **228**, the mandrel **230**, and the spring ring **232** slides in tandem along the longitudinal axis of the valve housing **202**. A lug **234** extends from the actuation arm **228** to engage the recess **224** on the first valve member **208**. In FIG. **2B**, the actuation assembly **226** is in a first position and the first valve member **208** is in a closed position. Should the actuation assembly **226** be pushed upward—sliding along the longitudinal axis of the valve housing **202**—into a second position, the lug **234** will engage the recess **224** exerting a force on the recess **224**. The force exerted on the recess **224** will cause the first valve member **208** to be pushed or rotated into an open position. When the first valve member **208** is in the open position, the valve bore **222** is substantially aligned with the central passage **204**, allowing fluids in the central passage **204** to pass through the valve bore **222**. Conversely, when the first valve member **208** is in the closed position, the valve bore **222** is misaligned with the central passage **204**, blocking fluids in the central passage **204** from moving past the first valve member **208**. In another embodiment (not shown), the actuation assembly may be in a second position while the first valve member is in a closed position. In this embodiment, the actuation assembly would correspondingly be in a first position when the first valve member is in the open position.

Referring now, specifically, to FIGS. **2B-2D**, a second, lower valve member **236** is connected to the actuation assembly **226**, and, specifically, the second valve member **236** is connected to the spring ring **232** portion of the actuation assembly **226**. The second valve member **236** is slideably disposed in the valve housing **202** and is configured to slide along the longitudinal axis of the valve housing **202**. The second valve member **236** may be characterized as a valve sleeve. The second valve member **236** may be positioned in an open or closed position to allow or prevent fluid communication between the central passage **204** and an annulus such as the well annulus **136** shown in FIG. **1**.

A first sealed annular volume **246** is formed between the second valve member **236** and the valve housing **202**. In one embodiment, the first sealed annular volume **246** is formed between the second valve member **236** and the portion of the valve housing **202** referred to as the rupture disc housing unit **242**. In some embodiments, a housing shoulder **252** may be formed in the rupture disc housing unit **242** and a corresponding sleeve shoulder **254** may be formed in the second valve member **236**. In this embodiment, the housing shoulder **252** and the sleeve shoulder **254** help form the first sealed annular volume **246**.

The first sealed annular volume **246** may be filled with low pressure air and, thus, may be characterized as an air chamber. Alternatively, the first sealed annular volume **246** may be filled with an inert gas or another gas such as nitrogen

A first annular seal **248** may be positioned above the first sealed annular volume **246** to provide sealing engagement between the second valve member **236** and the valve housing **202**. A second annular seal **250** may be positioned below the first sealed annular volume **246** to provide sealing engagement between the second valve member **236** and the valve housing **202**. In one embodiment, only the second annular seal **250** may be used. In another embodiment, the second annular seal **250** may be the primary seal and the first annular seal **248** may be a redundant seal that is in place in the event the primary seal fails.

A damper, such as a bumper **256** may be positioned in the first sealed annular volume **246** between the housing shoulder **252** and the sleeve shoulder **254**. The bumper **256** may be formed with staggered, inner and outer grooves **258**, **260**. The inner and outer grooves **258**, **260** allow the bumper **256** to partially collapse in the presence of a longitudinal force. In one embodiment, the inner and outer grooves **258**, **260** allow the bumper **256** to partially collapse or compress if the second valve member **236** slides upward relative to the valve housing **202** such that the sleeve shoulder **254** engages the housing shoulder **252** causing a compressive force to be applied to the bumper **256**. As shown in FIG. **2C**, the bumper **256** is positioned between the sleeve shoulder **254** and the housing shoulder **252**.

A non-electronic pressure sensor **262**, according to an illustrative embodiment, may be positioned in the first sealed annular volume **246**. In one embodiment, the non-electronic pressure sensor **262** is disposed within the inner groove **258** of the bumper **256**. In another embodiment, the non-electronic pressure sensor **262** is disposed in the outer groove **260** of the bumper **256**. The non-electronic pressure sensor **262** may be used to determine whether the first annular seal **248**, the second annular seal **250**, the first sealed annular volume **246**, or any combination of these components has failed or been compromised. One embodiment of a non-electronic pressure sensor that may be used as the non-electronic pressure sensor **262** shown in FIG. **2**C will be described in more detail below with reference to FIGS. **3** and **4**A-**4**B.

Referring still to FIGS. **2**C-**2**D, a second sealed annular volume **264** is formed between the second valve member **236** and the valve housing **202**, below the first sealed annular volume **246**. Specifically, the second sealed annular volume **264** may be formed between the second valve member **236** and the portion of the valve housing **202** referred to as the rupture disc housing unit **242**. The second valve member **236** may include an actuation shoulder **265** that defines a top portion of the second sealed annular volume **264**. The second annular seal **250** fluidly isolates the first sealed annular volume **246** and the second sealed annular volume **264**.

The portion of the valve housing **202** referred to as the rupture disc housing unit **242** includes a rupture port **266** disposed transversely through the rupture disc housing unit **242**. The rupture port **266** is aligned with and fluidly communicates with the second sealed annular volume **264**. Thus, the rupture port **266** is positioned below the second annular seal **250** and the first sealed annular volume **246**. A rupture disc **268** is disposed across rupture port **266** and held in place by a rupture disc retainer **270** that is attached to the rupture disc housing unit **242** at threaded connection **272**. The rupture disc **268** prevents fluid communication through the rupture port **266** until the rupture disc **268** is ruptured. The rupture port **266** is in fluid communication with an annulus, such as the well annulus **136** shown in FIG. **1**, and is configured to facilitate fluid communication between an annulus and the second sealed annular volume **264** in the event the rupture disc **268** is ruptured.

A lower portion of the rupture disc housing unit **242** is attached to a top portion of the bypass housing unit **244** at threaded connection **274**. A shear pin **276** is positioned below the rupture port **266** and initially locks the second valve member **236** with respect to the bypass housing unit **244**. In the event the shear pin **276** is sheared, the second valve member **236** is configured to slide relative to the valve housing **202**, which includes the bypass housing unit **244** portion of the valve housing **202**, along the longitudinal axis of the valve housing **202**.

Referring now specifically to FIG. **2**D, a sleeve port **278** is formed in the second valve member **236** and a housing port **280** is formed in the bypass housing unit **244**.

As shown, the sleeve port **278** and the housing port **280** are aligned and, thus, in fluid communication. When the sleeve port **278** and the housing port **280** are aligned, the second valve member **236** is in the open position. It should be further understood that when the housing port **280** is in fluid communication with the sleeve port **278**, the housing port **280** is also in fluid communication with the central passage **204**. Although not shown, when the sleeve port **278** and the housing port **280** are misaligned, the second valve member **236** is in the closed position, meaning there is no fluid communication between the housing port **280** and the sleeve port **278**.

Referring now to FIGS. **1**-**2**D, an illustrative mode of operation will be described. The testing string **122**, including the tester valve **200** shown in detail in FIGS. **2**A-**2**D, is lowered into the bore hole **106** with the first valve member **208** in the closed position and the second valve member **236** in the open position. When the first valve member **208** is closed, the portion of the testing string **122** above the first valve member **208** may be pressure tested to check for leaks in the testing string **122**.

Pressure may be applied to well annulus **136**. Once the pressure reaches a predetermined level, the rupture disc **268** will rupture, thereby communicating well-annulus fluid pressure into the second sealed annular volume **264**. The pressure will act upwardly on the actuation shoulder **265** formed on the second valve member **236**, causing sufficient upward force on the second valve member **236** to shear the shear pin **276**. The second valve member **236** will then slide or move upwardly causing the sleeve port **278** and the housing port **280** to become misaligned, thereby closing the second valve member **236**.

The pressure acting on the second valve member **236** may cause the second valve member **236** to move rapidly. The upward sliding movement of the second valve member **236** is limited when the sleeve shoulder **254** contacts the bumper **256**. The bumper **256** is crushed between the sleeve shoulder **254** and the housing shoulder **252**. The collapse of the bumper **256** cushions the blow and prevents damage that would be caused by the direct impact of sleeve shoulder **254** with the housing shoulder **252**. The tester valve **200** may be later removed from the well bore and disassembled and retrimmed for later use.

The upward sliding movement of the second valve member **236** will move the actuation assembly **226** upward with respect to the valve housing **202**. The upward movement of the actuation assembly **226** engages the first valve member **208**, rotating the first valve member **208** into its open position.

Now referring to FIGS. **3** and **4**A-**4**B, an illustrative embodiment of a non-electronic pressure sensor **300** will be described. The non-electronic pressure sensor **300** is similar to or may be the same as the non-electronic pressure sensor **262** described above in reference to FIG. **2**C. While the non-electronic pressure sensors **300** and **262** are being described for use in the first sealed annular volume **246** referenced in FIG. **2**C, it should be appreciated that the non-electronic pressure sensors described herein may be used in any sealed chamber for use in a wellbore to check the sealing integrity of the sealed chamber.

The non-electronic pressure sensor **300** includes a sealed, compressible container **302** having a fluid **314** sealed within the container **302**. The sealed, compressible container **302** may be formed from a material such as polytetrafluoroethylene that is both compressible and flexible. The material used to form the sealed, compressible container **302** may be non-permeable to prevent fluid leakage. The container **302** may be clear or opaque, and the container **302** may further be any shape, such as cylindrical or rectangular, as long as the container **302** is capable of freely expanding or contracting relative to a longitudinal center line **312** of the container **302**. In one embodiment, the container **302** may also have bending flexibility, allowing the container **302** to expand or contract while the container **302** is bent into a curved or arcing position. For example, FIGS. **4**A and **4**B illustrate an embodiment where the container **302** is disposed within an inner groove **308** of a bumper **310** (wherein the bumper **310** is similar to the bumper **256** illustrated in FIG. **2**C). As illustrated more clearly in FIG. **4**A, the container **302** is bent or curved to follow the curve of the bumper **310**. While the container **302** is curved, the container **302** is still capable of expanding or contracting along the longitudinal center line **312** of the container **302**.

Referring to FIGS. **4**A-**4**B, the bumper **310** may be formed with staggered, inner and outer grooves **308**, **314**. The inner and outer grooves **308**, **314** allow the bumper **310** to partially collapse in the presence of a longitudinal force. While the non-electronic pressure sensor **300** is shown in FIGS. **4**A-**4**B as disposed within the inner groove **308** of the bumper **310**, the non-electronic sensor **300** may, alternatively, be disposed in the outer groove **314** of the bumper **310**.

Referring again to FIGS. **3** and **4**A-**4**B, the sealed, compressible container **302** may be characterized as an aneroid bellows in one illustrative embodiment because the container **302** may be actuated into compressing or expanding without fluids passing through the container **302**. Additionally, the compressing and expanding may be facilitated by a wall **316** of the container **302** being pleated or corrugated. The fluid **314** in container **302** may be air or another compressible inert gas such as nitrogen.

The non-electronic pressure sensor **300** further includes a first magnet **304** and a second magnet **306**. The first and second magnets **304**, **306** may be positioned within the sealed, compressible container **302**. Furthermore, the first and second magnets **304**, **306** may be attached to opposing ends of the sealed, compressible container **302**. In another illustrative embodiment (not shown), the first and second magnets **304**, **306** may be attached to an outer surface **318** of the container **302**. The first and second magnets **304**, **306** may be oriented relative to each other such that a magnetic force represented by arrows **320** push the first and second magnets **304**, **306** apart. At atmospheric pressure, the first magnet **304** is a distance, d_{atm}, from the second magnet **306** (shown in FIG. **3**). For example, in an illustrative embodiment, the first magnet **304** and the second magnet **306** may be a distance apart of 1 inch at atmospheric pressure. In this example, when the testing valve is pressure tested, the first and second magnets **304**, **306** should maintain a distance of 1 inch if the sealed chamber, which the non-electronic pressure sensor **300** is disposed, has maintained its seal. If the first and second magnets **304**, **306** are a distance less than 1 inch, then the sealed chamber likely has a seal leak. For example, under this scenario, if the first and second magnets **304**, **306** are a distance of 0.5 inches apart, then the sealed chamber may have a 15 psi leak. Likewise, with a 30 psi leak, the first and second magnets **304**, **306** would be approximately 0.25 inch apart, and with a 60 psi leak the first and second magnets **304**, **306** would be approximately 0.125 inch apart. Pressure testing is commonly performed at pressures ranging from 5,000 to 15,000 psi. Using pressures in the 5,000 to 15,000 psi range to pressure test, would cause the first and second magnets **304**, **306** to essentially be 0 inches apart if there was a leak in the sealed chamber, making the first and second magnets **304**, **306** appear as a single magnet when checked with a sensing unit such as a Gauss meter.

In operation, a sensing unit (not shown) that may include a Gauss meter or a magnetometer may be used to determine the distance between the first and second magnets **304**, **306**. When the sensor **300** is positioned in a valve such as tester valve **124** of FIGS. **2**A-**2**D, the sensing unit may be moved along the outside of the valve housing **202** in the general vicinity of where the non-electronic pressure sensor **300** is located to determine the distance between the first and second magnets **304**, **306**.

Referring now to FIGS. **1-3**, an illustrative embodiment of how a non-electronic pressure sensor may operate in a tester valve will be described. The non-electronic pressure sensor may be positioned in a sealed, annular volume. First and second magnets disposed within the non-electronic pressure sensor will be separated by a first distance when a fluid within the annular volume is at a first pressure. Correspondingly, the first and second magnets will be separated by a second distance when a fluid within the annular volume is at a second pressure different than the first pressure. In a non-limiting illustrative embodiment, the second distance between the magnets may be less than the first distance between the magnets if the second pressure in the annular volume is greater than the first pressure in the annular volume.

In another illustrative embodiment, prior to employing a testing valve in a wellbore, a seal positioned between a first annular volume and a second annular volume may be tested. A user may monitor the distance between first and second magnets disposed within a non-electronic pressure sensor using a sensing unit while fluid pressure is increased in the second annular volume. The distance between the magnets will indicate whether the fluid pressure in the first annular volume increased in response to an increase of fluid pressure in the second annular volume. A change in distance between the magnets after fluid pressure is increased in the second annular volume may indicate a lack of seal integrity.

Referring now to FIGS. **5-6**, additional, non-limiting embodiments in which the non-electronic pressure sensor **300** may be used are described. Referring specifically to FIGS. **5-6**, a battery operated pressure gauge **400** that may be used as part of a wireline tool (not shown) is illustrated. The battery operated pressure gauge **400** may include a battery housing **402** that sealingly encloses a battery pack **404** and a pressure sensor **406**. The non-electronic pressure sensor **300** may be sealingly positioned within the battery housing **402**. The battery pack **404** may be comprised of lithium batteries, especially if precise pressure data is needed. Lithium batteries have been known to explode during tool maintenance if the lithium batteries have been exposed to conducting fluids. Using the non-electronic pressure sensor **300** to detect whether the pressure within the battery housing **402** has been compromised may act as a warning device to inform users conducting maintenance to proceed with caution when opening the battery housing **402**.

Referring now to FIG. **7**, the non-electronic pressure sensor **300** as described herein may further be used in conjunction with another embodiment of an electronic pressure gauge **500** that may be used, for example, in a wireline tool (not specifically shown). The electronic pressure gauge **500** shown in FIG. **7** is positioned in a sealed air chamber (not shown). As illustrated, a quartz pressure sensor **502** is connected by wires **504** to a connector **506**. The non-electronic pressure sensor **300** may be used as described above to determine whether the sealed air chamber surrounding the electronic pressure gauge **500** has been compromised. It is not uncommon for fluids downhole to be comprised of natural gases, including poisonous gases such as hydrogen sulfide. Thus, knowing whether a sealed air chamber has been compromised may become a matter of safety if a user unknowingly opens an electronic housing containing a gas such as hydrogen sulfide.

Referring now to FIG. **8**, the non-electronic pressure sensor **300** as described herein may further be used in conjunction with an electronic circuit board **600**. The electronic circuit board **600** may be used, for example, in a wireline tool (not specifically shown). The electronic circuit board **600** illustrated in FIG. **8** is positioned in a sealed air chamber (not shown). The non-electronic pressure sensor **300** may be used as described above to determine whether the sealed air chamber surrounding the electronic circuit board **600** has been compromised.

The orientation, and specific mechanisms of the testing valve described above are for illustrative purposes only. It should be understood that other configurations of testing valves may be used. For example, in another illustrative embodiment, the testing valve used could have a mirroredorientation to the testing valve described above. E.g., the second valve member **236** may be positioned above the first valve member **208** and when the second valve member **236** is in the closed position a downward force acts upon the first valve member **208** to push the first valve member **208** into the open position.

It should be apparent from the foregoing that an invention having significant advantages has been provided. While the invention is shown in only a few of its forms, it is not limited to only these embodiments but is susceptible to various changes and modifications without departing from the spirit thereof.

I claim:

1. A valve for use in a wellbore, the valve comprising:
- a housing configured to form a central passage;
- a first valve member positionable in an open or closed position to allow or prevent flow through the central passage;
- a second valve member positionable in an open or closed position to allow or prevent fluid communication between the central passage and an annulus positioned between the valve and the wellbore;
- an actuation assembly connected to the first valve member and the second valve member, the actuation assembly movable between a first position and a second position to selectively position each of the first valve member and the second valve member;
- a sealed annular volume formed between the second valve member and the housing; and
- a pressure sensor disposed in the sealed annular volume, the pressure sensor comprising:
  - a sealed, compressible container, and
  - a first magnet and a second magnet positioned within the sealed, compressible container, the first and second magnets separated by a first distance when a fluid within the sealed annular volume is at a first pressure,
  - wherein the first and second magnets are separated by a second distance when the fluid in the sealed annular volume is at a second pressure; and
  - a sensing unit positioned on the exterior of the valve housing adjacent to the pressure sensor to determine whether the second distance between the first and second magnets at the second pressure is different from the first distance at the first pressure.

2. The valve of claim **1**, wherein the second pressure is greater than the first pressure and the second distance is less than the first distance.

3. The valve of claim **1**, wherein:
- responsive to the actuation assembly being in the first position, the first valve member is in the closed position and the second valve member is in the open position; and
- responsive to the actuation assembly being in the second position, the first valve member is in the open position and the second valve member is in the closed position.

4. The valve of claim **1**, wherein:
- responsive to the actuation assembly being in the first position, the first valve member is in the open position, and the second valve member is in the closed position; and
- responsive to the actuation assembly being in the second position, the first valve member is in the closed position and the second valve member is in the open position.

5. The valve of claim **1**, wherein the actuation assembly is in the first position when the valve is initially deployed in the wellbore.

6. The valve of claim **1**, wherein the first valve member is a ball valve member positioned within the housing and rotatable between the open and closed positions.

7. The valve of claim **1**, wherein the second valve member is a valve sleeve slidably positioned within the housing, the valve sleeve having a sleeve port that aligns with a housing port in the housing when the valve sleeve is in the open position, the sleeve port and the housing port being misaligned when the valve sleeve is in the closed position.

8. The valve of claim **1**, wherein the first and second magnets are orientated such that a magnetic force between the first and second magnets pushes the first and second magnets apart.

9. The valve of claim **1**, wherein the actuation assembly further comprises:
- an actuation arm operably associated with the first valve member to position the first valve member in the open position or the closed position;
- a spring ring operably associated with the second valve member; and
- a mandrel disposed between the actuation arm and the spring ring, an upper portion of the mandrel attached to the actuation arm and a lower portion of the mandrel attached to the spring ring;
- wherein the second valve member is slidably disposed within the housing and connected to the actuation assembly for mutual, axial sliding movement within the housing, the second valve member having a valve member port there through configured to be aligned with a housing port disposed through the housing when the second valve member is in the open position, the second valve member port and the housing port being misaligned when the second valve member is in the closed position.

10. The valve of claim **1**, further comprising:
- an rupture port disposed in the housing and capable of providing fluid communication between the annulus and a second annular volume between the housing and the actuation assembly;
- a rupture disk disposed in the rupture port to prevent fluid communication through the rupture port until the rupture disk is ruptured; and
- a seal positioned between the first annular volume and the second annular volume to prevent fluid communication between the first annular volume and the second annular volume.

11. The valve of claim **10**, wherein prior to deployment of the valve in the wellbore, the seal may be tested by increasing a pressure of fluid in the second annular volume, and determining by monitoring of a distance between the first and second magnets whether the pressure of the fluid in the first annular volume increases.

12. The valve of claim **1**, further comprising a bumper disposed in the sealed annular volume, wherein the pressure sensor is disposed within a groove of the bumper.

13. An apparatus for use in a wellbore, the apparatus comprising:
- a housing having at least one chamber capable of receiving a fluid;
- a sealed annular volume; and
- a pressure sensor disposed in the sealed annular volume, the sensor comprising:
  - a sealed, compressible container, and
  - a first magnet and a second magnet positioned within the sealed, compressible container, the first and second magnets separated by a first distance when a fluid within the sealed annular volume is at a first pressure,
  - wherein the first and second magnets are separated by a second distance when the fluid in the sealed annular volume is at a second pressure; and

a sensing unit positioned on the exterior of the valve housing adjacent to the pressure sensor to determine whether the second distance between the first and second magnets at the second pressure is different from the first distance at the first pressure.

14. The apparatus of claim **13**, wherein the sensing unit is positionable by a user outside of the housing to determine a distance between the first and second magnets.

15. The apparatus of claim **14**, wherein the sensing unit is a Gauss meter.

16. The apparatus of claim **14**, wherein the sensing unit and the pressure sensor are used to determine whether the chamber is fluidly sealed.

17. The apparatus of claim **13** further comprising:

a second chamber positioned within the housing; and

a seal positioned between the first chamber and the second chamber to fluidly isolate the first chamber from the second chamber.

18. The apparatus of claim **17**, wherein the sensing unit is positionable outside of the first chamber as a pressure of a fluid within the second chamber is changed to determine if a distance between the magnets changes, thereby indicating a lack of integrity of the seal.

19. The apparatus of claim **13**, wherein the first and second magnets are orientated such that a magnetic force between the first and second magnets pushes the first and second magnets apart.

20. A method of determining whether a seal has failed between a first chamber and a second chamber in a downhole apparatus, the first chamber having disposed therein a sealed, compressible container, the container having first and second magnets disposed therein, the first and second magnets being separated by a first distance when a fluid within the sealed, compressible container is at a first pressure, the method comprising:

changing a pressure of fluid within the second chamber;

determining a measured distance between the magnets; and

comparing the measured distance to the first distance.

21. The method of claim **20** further comprising:

determining that the seal has failed if the measured distance is different than the first distance.

22. The method of claim **20**, wherein changing the pressure further comprises increasing the pressure.

23. The method of claim **20**, wherein determining the measured distance is performed prior to delivering the downhole apparatus into a wellbore.

24. A method for determining whether a chamber in a downhole apparatus is sealed, the chamber having disposed therein a sealed, compressible container, the container having first and second magnets disposed therein, the first and second magnets being separated by a first distance when a fluid within the sealed, compressible container is at a first pressure, the method comprising:

prior to delivering the downhole apparatus into a wellbore, determining a measured distance between the magnets; and

comparing the measured distance to the first distance.

25. The method of claim **24** further comprising:

determining that the chamber is no longer sealed if the measured distance is different than the first distance.

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